WEST ENERGY LTD.

Beneath the surface of an ancient sea, 380 million years ago, the Devonian reefs and their treasures were deposited …

ANNUAL REPORT 2006

CORPORATE PROFILE

West Energy Ltd. is a public energy exploration company operating in western Canada. The Company was incorporated in December, 2002, and attained public status on October 8, 2004, when its shares commenced trading on The Toronto Stock Exchange under the symbol "WTL". Since its inception, West has focused its efforts in the prolific light oil Nisku reef fairway of west central Alberta. Significant investment in land, seismic and a large facility complex has established West as one of the major players along the Pembina Nisku trend. In late 2006, West defined an additional light sweet oil exploration project area where an extensive 3D seismic program is being completed. Exploration drilling is expected to commence in the second half of 2006.

ADDITIONAL INFORMATION

The information contained in this annual report represents only a portion of current information available on West Energy Ltd. Readers are encouraged to read West's Annual Information Form and Management Information Circular. These documents together with quarterly reports, news releases and corporate presentations are available by visiting the Company's website at www.westenergy.ca. Additional information regarding the Company, including all continuous disclosure documents, can be obtained on SEDAR at www.sedar.com. If you require a hard copy of any of these documents please call our main office number (403)265-5202.

ANNUAL GENERAL MEETING

The Annual General Meeting of the shareholders of West Energy Ltd. will be held at 10:00 a.m. on April 26, 2007 in the Strand/Tivoli Room of the Metropolitan Conference Centre, 333 - 4th Avenue S.W., Calgary, Alberta. Shareholders who are not able to attend the meeting in person are encouraged to complete and mail in their proxies.

CONTENTS

About our Cover

The illustration on the cover depicts the environment in which the shoals and pinnacle reefs were deposited during Devonian time hundreds of millions of years ago when most of Alberta was underwater.

OPERATING AND FINANCIAL HIGHLIGHTS

	Three months ended December 31,		Year ended December 31,	
	2006	2005	2006	2005
	(unaudited)	*(unaudited)*		
Operating				
Production				
Natural gas (Mcf/d)	2,908	1,651	3,216	1,447
Crude oil and NGLs (Bbls/d)	2,306	1,605	2,218	1,015
Barrels of oil equivalent (Boe/d @ 6:1)	2,791	1,880	2,754	1,256
Prices				
Natural gas (per Mcf)	$ 7.57	$ 12.45	$ 7.54	$ 9.54
Crude oil and NGLs (per Bbl)	$ 58.84	$ 66.83	$ 69.85	$ 64.15
Revenue (per Boe)	$ 56.50	$ 67.98	$ 65.06	$ 62.82
Royalties (per Boe)	$ 16.72	$ 18.33	$ 15.33	$ 15.15
Operating costs (per Boe)	$ 12.72	$ 11.10	$ 12.42	$ 8.87
Operating netback (per Boe)	$ 27.06	$ 38.55	$ 37.31	$ 38.80
General and administrative (per Boe)	$ 2.97	$ 3.10	$ 2.84	$ 3.48
Interest expense (per Boe)	$ 1.07	$ 2.19	$ 0.85	$ 1.36
Corporate netback (per Boe)	$ 23.02	$ 33.26	$ 33.62	$ 33.96
Gross Company Reserves (Mboe)				
Proven	5,534	4,070	5,534	4,070
Proven plus probable	8,628	6,786	8,628	6,786
Wells drilled - Gross (net)				
Gas	1/(0.15)	1/(1.00)	8/(2.06)	7/(5.65)
Oil	2/(0.56)	2/(0.17)	8/(6.40)	6/(0.29)
Service (water source and injection)	4/(3.40)	–/(0.00)	5/(4.41)	2/(0.32)
Abandoned	–/(0.00)	1/(1.00)	5/(3.58)	2/(2.00)
Total	7/(4.11)	4/(2.17)	26/(16.45)	17/(8.26)
Drilling success rate (excluding service wells)	100%/(100%)	75%/(54%)	80%/(70%)	76%/(72%)
Financial *(000s, except per share amounts)*				
Oil and gas revenues	$ 14,730	$ 11,960	$ 66,929	$ 29,464
Funds from operations	$ 6,058	$ 5,797	$ 35,178	$ 15,993
Per share - basic	$ 0.10	$ 0.11	$ 0.58	$ 0.32
- diluted	$ 0.09	$ 0.10	$ 0.55	$ 0.29
Cash flow from operating activities	$ 5,095	$ 7,586	$ 29,438	$ 17,858
Per share - basic	$ 0.08	$ 0.15	$ 0.49	$ 0.36
- diluted	$ 0.08	$ 0.13	$ 0.46	$ 0.32
Net income (loss)	$ (6)	$ 1,098	$ 6,244	$ 3,357
Per share - basic	$ 0.00	$ 0.02	$ 0.10	$ 0.07
- diluted	$ 0.00	$ 0.02	$ 0.10	$ 0.06
Working capital (deficiency)	$ (18,524)	$ (11,574)	$ (18,524)	$ (11,574)
Capital expenditures	$ 21,781	$ 36,274	$ 82,097	$ 91,870
Total assets	$ 233,191	$ 180,809	$ 233,191	$ 180,809
Common shares				
Outstanding	64,212	58,661	64,212	58,661
Weighted average - basic	62,184	51,976	60,228	50,288
- diluted	66,194	57,456	64,394	55,107

PRESIDENT'S LETTER TO SHAREHOLDERS

West achieved the following in 2006:

- completed and commissioned our Paddy Creek battery complex and related infrastructure;
- drilled 26 (16.45 net) wells resulting in 8 (6.40 net) oil wells, 8 (2.06 net) gas wells, 5 (4.41 net) water source and injection wells and 5 (3.58 net) abandonments;
- the 26 wells included 18 (14.64 net) Pembina Nisku wells resulting in 8 (6.40 net) oil wells, 1 (0.33 net) gas well, 5 (4.41 net) water source and injection wells and 4 (3.50 net) abandonments.
- discovered 5 new oil pools and 1 new gas pool in the Pembina Nisku fairway;
- increased production by 119% from 2005 levels;
- increased funds from operations by 120%;
- increased net income by 86%;
- received approvals for three enhanced oil recovery (EOR) applications of which two EOR schemes were initiated in December, 2006 and the third in early 2007;
- increased proven reserves to 5.5 MMboe and proven plus probable reserves to 8.6 MMboe at December 31, 2006; and
- completed a flow-through share equity financing at $7.25 per share in November 2006 for gross proceeds of $30 million.

West's commitment to the Pembina Nisku fairway continued in 2006 with a capital expenditure program of $77 million to acquire land, seismic, drill 18 wells and construct facilities.

The evaluation of 3D seismic data by West's exploration team has been instrumental in our ability to discover new hydrocarbon pools in the Pembina Nisku fairway. Our 2006 oil discoveries consisted of two at Violet Grove and one each at Lodgepole, Paddy Creek and Crossfire. At the end of 2006, West had an inventory in excess of 50 drillable Nisku prospects along the Pembina fairway with an average working interest of 65%.

As we move forward into 2007 while our focus will be the Pembina Nisku fairway, we have recently completed new 3D seismic programs in both Crossfire and a new exploration project area. We have commenced the acquisition of lands prospective for light sweet oil in this new exploration area.

West's objectives for 2007 include:

- increasing our current production level of 4,500 – 5,200 Boe/d by bringing on-stream our shut-in wells which have an incremental production potential of 2,500 Boe/d;
- drill up to 16 Pembina Nisku wells;
- construct Crossfire facilities to bring this area on-stream; and
- drill wells in our new exploration area.

Funding for West's 2007 capital program will be driven primarily by increased production and cash flow. We will continue our policy of restricting capital expenditures for drilling, equipping and well site facilities to cash flow and utilizing our borrowing base when required for land and facilities. Drilling success at Crossfire expanded the Pembina Nisku fairway 10 miles to the northeast where we have now secured sufficient additional drilling prospects to initiate the construction of facility infrastructure. Our first Crossfire discovery should be on stream by the third quarter.

Discussions with industry participants in the Pembina Nisku fairway to initiate and complete enhanced oil recovery projects to maintain reservoir pressure is ongoing. All industry participants understand the importance of maintaining reservoir pressure to maximize recovery of hydrocarbons associated with Nisku pools.

We appreciate the efforts of all members of West's team and are thankful for the continued support we have received from our shareholders during a year with many challenges.

On behalf of the Board of Directors

Ken McCagherty
President and Chief Executive Officer

March 19, 2007

2006 OPERATIONS

Pembina Nisku Geology

The Devonian age reefs of the Nisku have been the focus of oil and gas exploration in the Pembina area since the discovery of the Nisku/Zeta Lake pinnacle reefs during the mid 1970's by Chevron. In the past, Zeta Lake reefs along the outer ramp trend were identified and drilled primarily using 2D seismic. In the 1990's 3D seismic was used successfully to image Nisku reefs or shoals within the inner ramp trend opening up a new play in the area. These Nisku reefs were bio-constructed some 380 million years ago, on a dynamic carbonate ramp setting influenced by wind driven currents and hurricanes. This depositional setting is remarkably similar to that observed in the present day, on the Belize carbonate platform in the western Caribbean.

The Nisku Formation consists of several members. The first being the basal Lobstick and Bigoray carbonate units which developed as ramps upon which the Nisku shoals/Zeta Lake pinnacle reefs initiated and flourished. The larger shoals and pinnacle reefs developed discrete lagoonal and porous margin facies. Encapsulating these shoals and reefs are off-reef Cynthia shales or the Dismal Creek mudstones providing a competent seal to trap hydrocarbons. The primary target reservoir is the dolomitized margins located in the northeast position of the shoals/reefs and typically have porosities ranging from 9% to 15%, which is indicative of reservoir storage capacity, and permeability up to 10 darcies, which is indicative of reservoir flow capacity. This reservoir generally is greater than 15 meters in uniform thickness. The dolomitized lagoon reservoir facies, while productive, is usually thinner and has streaky porosity of less than 7%.

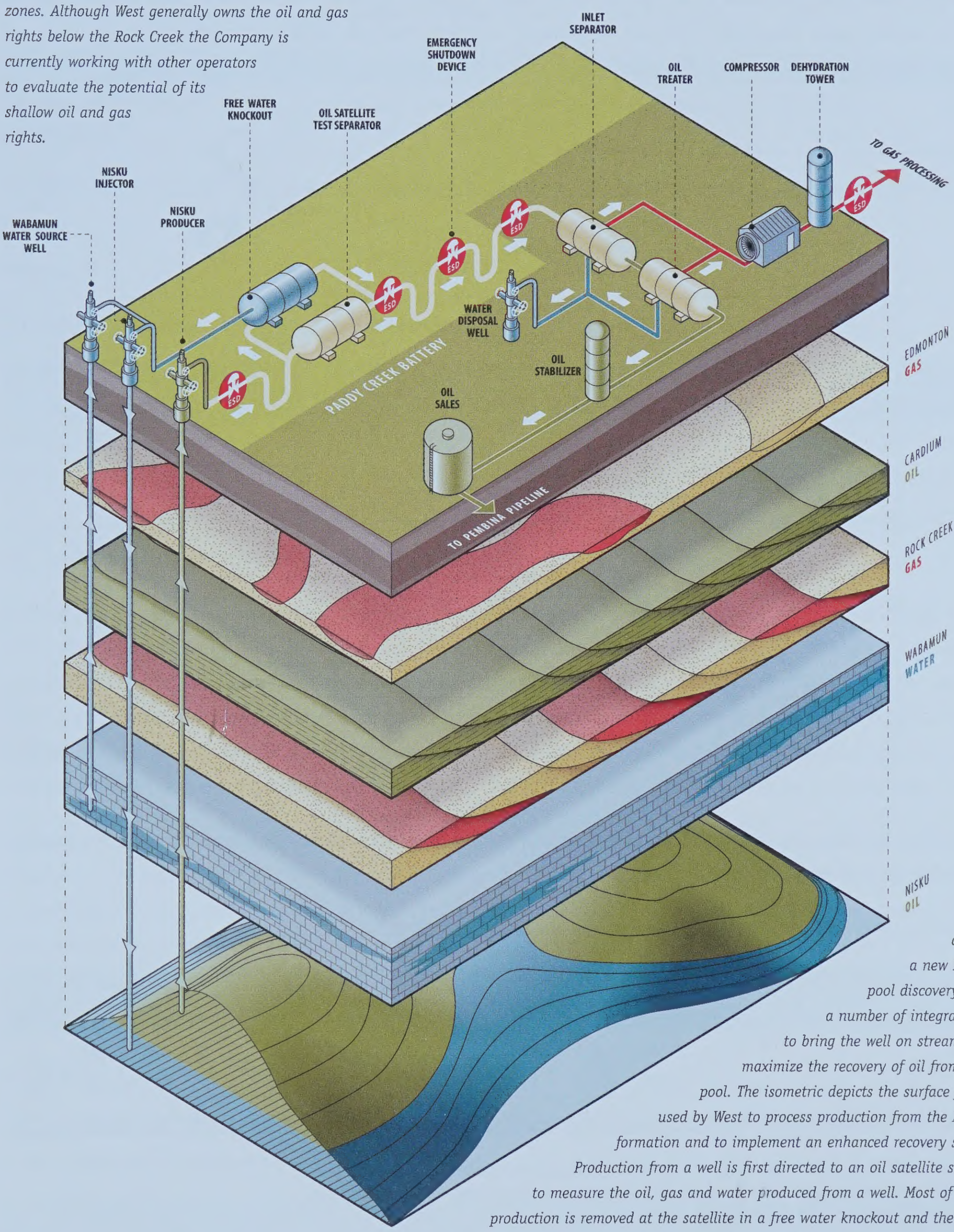
West has specifically targeted the oil prone area of the Nisku inner ramp fairway where the shoals/reefs are at depths of 2,200 to 3,200 meters. These oil pools contain light oil with a gravity ranging from 38 to 42 degrees API with associated gas that is sour with H_2S concentrations ranging from 0 - 30%. Successful wells in the trend are capable of producing from 500 to 2,000 Boe/d with a reserve potential exceeding 1.0 Mmboe per well. In West's focus area, the industry has drilled approximately 102 wells since January, 2001. The overall industry success rate in this play system has been 85% for development locations and 55% success rate for exploration locations. The key geological risks along this fairway are reef identification as the porous reef is sometimes confused with shales or tight carbonate mudstones, which can have similar seismic attributes, and whether an extensive lateral seal exists, which determines the hydrocarbon column.

The cost of drilling a successful Pembina Nisku well is approximately \$5.0 million, including \$2.4 million for intangible drilling and completion, tangible completion costs of \$0.8 million and \$1.8 million for facilities.

Other Prospects in the Pembina Fairway

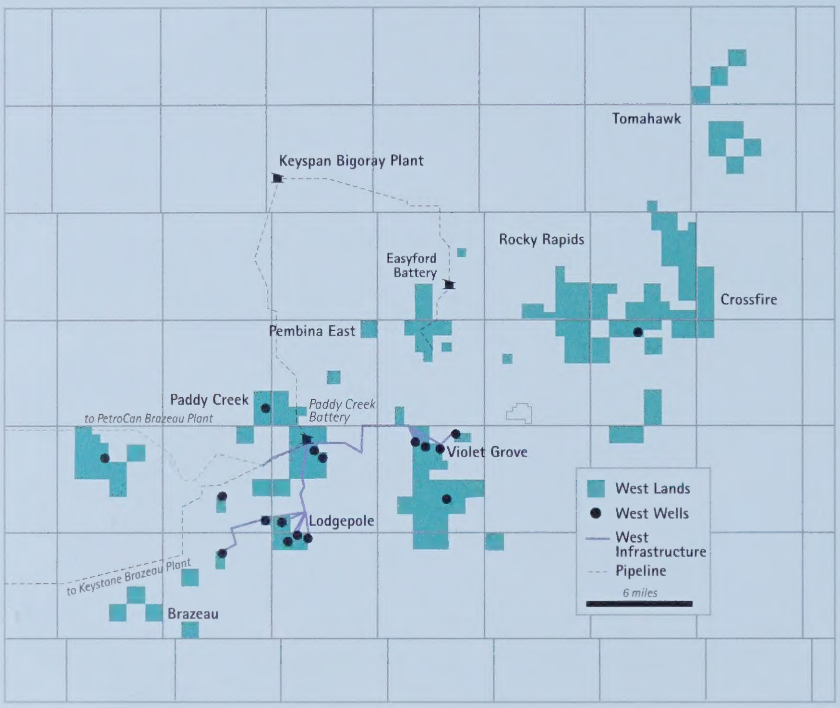
The Pembina fairway consists of several other formations that produce hydrocarbons or are prospective for hydrocarbon entrapment. The shallowest being the Edmonton Group, at a depth of 180 to 600 metres, in which fluvial or river channel sands trap gas. Below this zone, at approximately 1,250 metres, is the Cardium oil pool, which was discovered in the early 1950's by Mobil and Canadian Superior, and has been the target of thousands of oil wells. Below the Cardium is the Rock Creek formation, a

The isometric illustrates the many complexities and opportunities associated with the development of the Pembina Nisku trend. The Nisku zone lies beneath a number of productive formations in the area and the drilling of a Nisku well affords the ability to see the hydrocarbon potential of the other zones. Although West generally owns the oil and gas rights below the Rock Creek the Company is currently working with other operators to evaluate the potential of its shallow oil and gas rights.



The drilling of a new Nisku oil pool discovery requires a number of integrated steps to bring the well on stream and to maximize the recovery of oil from the pool. The isometric depicts the surface facilities used by West to process production from the Nisku formation and to implement an enhanced recovery scheme. Production from a well is first directed to an oil satellite separator to measure the oil, gas and water produced from a well. Most of the water production is removed at the satellite in a free water knockout and then injected back into the Nisku aquifer. Additional water is added from a Wabamun water source well and injected back into Nisku aquifer to replace the volume of oil and gas removed and thus maintain the pressure in the oil pool. The remaining oil and gas emulsion is piped to an inlet separator at the battery where the gas is removed and then to the oil treater to remove the last of the water and gas from the oil. All the gas is piped to a compressor and passed through a dehydration tower to remove any remaining water in the gas before it is sent to a third party pipeline and processing plant for gas liquids (NGLs) and sour gas (H2S) removal and then sold. From the oil treater, the oil is sent to a tank and then shipped into the oil sales line. The entire process is a closed loop system meaning it is designed to ensure no leakage of sour gas to the atmosphere. Throughout the entire process West has installed a number of emergency shutdown devices (more than shown in the illustration), with H2S monitors that will automatically shutdown the whole operation.

prospective paralic, shoreface tight sand gas play at a depth of 1,750 metres requiring advanced frac technology to produce gas. Below the Rock Creek formation, is the Devonian Wabamun formation located at a depth of 2,050 metres and is the current water source for enhanced oil recovery, secondary pressure maintenance schemes in the Nisku oil reservoirs, producing in the Pembina area.



LAND

The map above indicates the location of West's lands along the Pembina Nisku fairway, its successful wells, the location of the Paddy Creek battery and infrastructure.

The following table sets forth West's land position at December 31, 2006.

	Developed			Undeveloped			Total		
(acres)	Gross(1)	Net(2)	WI%	Gross(1)	Net(2)	WI%	Gross(1)	Net(2)	WI%
Pembina	7,360	3,491	47%	50,880	31,574	62%	58,240	35,065	60%
Other	14,777	2,210	15%	46,880	19,675	42%	61,657	21,885	35%
Total	22,137	5,701	26%	97,760	51,249	52%	119,897	56,950	47%

Notes:
(1) "Gross" means the total number of acres in which West has an interest.
(2) "Net" means the aggregate of the percentage working interests of West in the Gross lands.

West spent a total of $3.0 million on land acquisitions in 2006.

SEISMIC

The Company's seismic data base at December 31, 2006 consisted of the following:

	Proprietary	Trade	Total
3D data (mi^2)	265	305	570
2D data (mi)	129	1,284	1,413

In 2006, West shot three proprietary 3D programs totaling 49 square miles primarily in the Crossfire and Ante Creek areas.

Drilling

The following table sets forth West's drilling activity for the year ended December 31, 2006.

	Oil Wells			**Gas Wells**			**Service**[1]			**D&A**			**Total**		
	Gross	Net	WI%	Gross	Net	WI%	Gross	Net	WI%	Gross	Net	WI%	Gross	Net	WI%
Pembina	8	6.40	80	1	0.33	33	5	4.41	88	4	3.50	88	18	14.64	81
Other	–	–	–	7	1.73	25	–	–	–	1	0.08	8	8	1.81	23
Total	8	6.40	80	8	2.06	26	5	4.41	88	5	3.58	72	26	16.45	63

Notes:
(1) Service wells are wells are either water injection or water source wells.

Drilling Nisku exploration wells along the Pembina trend requires wells be licensed as critical sour (Level 3 E-610) under the Alberta Energy and Utilities Board (AEUB) regulations. The high H2S content of the sour solution gas combined with the possible prolific flow rates necessitates the critical sour classification for exploration wells. The drilling of a critical sour well requires extensive emergency response planning, resident consultation and a technical drilling program review before a well is ultimately licensed and drilled. West has maintained a positive working relationship with concerned residents and is confident it can continue to obtain licenses on a timely basis.

In Pembina, West drilled 9 successful wells resulting in 1 new gas pool and 5 new oil pool discoveries and 3 pool extensions. The most significant Nisku oil pool discovery in 2006 was at Crossfire 13-02-50-06W5 (W.I. 100%). The well drilled into a thick dolomite Nisku reef with a hydrocarbon column of 23.6 metres, and extended commercial Nisku discoveries by 10 miles to the northeast. During the 7 hour test period the well produced the equivalent of 3,043 Boe/d (2,631 Bbl/d of oil and 2,473 Mcf/d of gas), no water and an H2S content of 3.5%. The Company plans to construct facilities and a pipeline in 2007 and have the well on stream by the end of June, 2007.

PRODUCTION

The following table sets forth West's total production, average daily production and average prices received for the three months ended December 31, 2006.

	Total Production			**Average Daily Production**			**Average**
	Pembina	Other	Total	Pembina	Other	Total	**Price**
Oil (Bbls)	141,314	5,163	146,477	1,536	56	1,592	$60.18
NGLs (Bbls)	64,089	1,568	65,657	697	17	714	$55.83
Natural Gas(Mcf)	226,417	41,109	267,526	2,461	447	2,908	$7.57
Total (Boe)	243,139	13,583	256,722	2,643	148	2,791	$56.50

The following table sets forth West's total production, average daily production and average prices received for the year end 2006.

	Total Production			Average Daily Production			Average
	Pembina	Other	Total	Pembina	Other	Total	Price
Oil (Bbls)	567,956	18,279	586,235	1,556	50	1,606	$71.86
NGLs (Bbls)	218,469	4,751	223,220	599	13	612	$64.55
Natural Gas(Mcf)	977,156	196,540	1,173,696	2,677	539	3,216	$7.54
Total (Boe)	949,284	55,787	1,005,071	2,601	153	2,754	$65.06

The major capital expenditure undertaken by the Company in late 2005 was the construction of the battery complex in the Paddy Creek area. Although the Pembina Nisku fairway is in the middle of one of Canada's largest oil fields for a shallower formation, the sour solution gas associated with the Nisku formation required that new sour spec gathering and oil separation facilities had to be constructed. Attempts to build a central battery for all operators in the area, which would be operated by an independent facilities entity, were unsuccessful. To ensure the Company had sufficient processing capacity to manage its production needs, West commenced construction of its own battery in 2005. The project was completed in March, 2006.

The Paddy Creek battery complex consists of a 10,000 Boe/d (8,000 Bbls/d of fluids and 17 MMcf/d of raw gas at 31% H2S) battery complete with mole sieve dehydration, compression, oil stabilization, storage and sales pipeline. In addition the complex includes well site facilities and pipelines, two satellite batteries, and 15 miles of central gathering system connecting the battery with wells to the south, east and west along the play fairway. The battery has been designed with excess capacity to accommodate West's, and other industry participants, future drilling activity in the Lodgepole, Lodgepole West, Paddy Creek and Violet Grove areas. The facility was also designed for expansion to ensure the battery can handle third party demands in the area.

Following completion of the Paddy Creek battery complex the Company increased its production from the Pembina area. Production was later curtailed as West and certain operators shut-in producing pools pending implementation of enhanced oil recovery ("EOR") schemes to maintain reservoir pressures. At the end of 2006, West had production shut-in at the Lodgepole, Violet Grove and Paddy Creek areas awaiting implementation of and/or increased reservoir pressure from EOR schemes. West's effort to bring on its production at expected well capabilities has been hampered by the industry's lack of joint cooperation to replace total voidage along the Pembina Nisku trend. West has voluntarily shut-in wells to reduce voidage and is injecting enough water to replace its production and increase reservoir pressure. The participation of other operators to reach the same pressure maintenance targets is required to optimize production along the Nisku trend. West continues to work with the other operators to resolve this issue.

RESERVES

All of West's reserves were independently evaluated by GLJ Petroleum Consultants Ltd. ("GLJ") with an effective date of December 31, 2006 using the standards of reporting required under the Canadian Securities Administrators' National Instrument 51-101. Proven reserves are classified as those that can be estimated with a high degree of certainty, at least 90% probability that the actual quantities recovered will equal or exceed the estimated reserves. Probable reserves are classified as those additional reserves that can be estimated with at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proven plus probable reserves. The Company believes that the proven plus probable reserves represent the most likely recoverable quantities.

West's reserves are mainly within the Nisku formation and are assessed using a combination of performance and volumetric estimates. The volumetric estimates are based on a combination of basic well data and seismic information. The seismic character identifies thick reef margin but does not accurately identify pool boundaries needed to calculate volume. In some cases reserves were determined from the volumetric estimates of original oil in place combined with an estimated recovery factor and actual well performance will adjust these parameters over time. Most of the Company's Nisku reserves have been subject to intermittent production because of the delays experienced in implementing the EOR schemes discussed earlier thus requiring a larger variation between the proven and proven plus probable reserves. All the Company's reserves are located in Canada in the province of Alberta.

The reconciliation of the Company's working interest reserves before royalties, from January 1, 2006 to December 31, 2006 is set forth below. The before tax present values, based on forecast prices and costs, are also provided.

	Light, Medium and Heavy Oil			**Natural Gas**			**Natural Gas Liquids**		
Factors	Proven (Mbbl)	Probable (Mbbl)	Proven plus Probable (Mbbl)	Proven (MMcf)	Probable (MMcf)	Proven plus Probable (MMcf)	Proven (Mbbl)	Probable (Mbbl)	Proven plus Probable (Mbbl)
January 1, 2006	2,790	1,691	4,481	4,490	3,500	7,990	457	308	765
Drilling extensions	74	30	104	1,994	1,110	3,104	60	22	82
Improved recovery	2	–	2	–	–	–	–	–	–
Technical revisions	876	(99)	777	1,179	(1,259)	(80)	(54)	(171)	(225)
Discoveries	838	652	1,490	944	627	1,571	38	24	62
Dispositions	–	–	–	–	–	–	–	–	–
Production	(688)	–	(688)	(1,204)	–	(1,204)	(93)	–	(93)
December 31, 2006	3,892	2,274	6,166	7,403	3,978	11,381	408	183	591

	Barrels of Oil Equivalent		
Factors	Proven (Mboe)	Probable (Mboe)	Proven plus Probable (Mboe)
January 1, 2006	3,996	2,582	6,578
Drilling extensions	466	237	703
Improved recovery	2	–	2
Technical revisions	1,018	(480)	538
Discoveries	1,034	781	1,815
Dispositions	–	–	–
Production	(982)	–	(982)
December 31, 2006	5,534	3,120	8,654
Net present values, before income taxes discounted at:	($000)	($000)	($000)
0%	$ 166,167	$ 95,587	$ 261,754
5%	$ 148,103	$ 72,244	$ 220,347
8%	$ 139,410	$ 62,765	$ 202,176
10%	$ 134,308	$ 57,622	$ 191,930
15%	$ 123,454	$ 47,608	$ 171,061

Note:
Columns may not add due to rounding. Included in the determination of undiscounted net present values are $9.1 million of development costs for the total proven category and $17.1 million of development costs for the total proven plus probable category.

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the GLJ Report were as follows:

	Oil				Natural Gas					
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Cromer Medium 29.3° API ($Cdn/Bbl)	AECO Gas Price ($Cdn/ MMBTU)	Edmonton Butane ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Pentanes Plus ($Cdn/Bbl)	Inflation Rates(1) %/Year	Exchange Rate (2) ($US/$Cdn)
Forecast										
2007	62.00	70.25	39.25	61.25	7.20	56.25	45.00	71.75	2.0	0.870
2008	60.00	68.00	40.00	59.25	7.45	50.25	43.50	69.25	2.0	0.870
2009	58.00	65.75	39.75	57.25	7.75	48.75	42.00	67.00	2.0	0.870
2010	57.00	64.50	39.75	56.00	7.80	47.75	41.25	65.75	2.0	0.870
2011	57.00	64.50	40.25	56.00	7.85	47.75	41.25	65.75	2.0	0.870
2012	57.50	65.00	41.50	56.50	8.15	48.00	41.50	66.25	2.0	0.870
2013	58.50	66.25	42.50	57.75	8.30	49.00	42.50	67.50	2.0	0.870
2014	59.75	67.75	43.50	59.00	8.50	50.25	43.25	69.00	2.0	0.870
2015	61.00	69.00	44.25	60.00	8.70	51.00	44.25	70.50	2.0	0.870
2016	62.25	70.50	45.25	61.25	8.90	52.25	45.00	72.00	2.0	0.870
2017	63.50	71.25	46.00	62.50	9.10	53.00	46.00	73.25	2.0	0.870
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.870

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

FINDING AND DEVELOPMENT COSTS

An exploration company's profitability will ultimately depend on its success of investing risk capital compared to the reserves it discovers and the netbacks it receives from those reserves. Since inception West has invested $245 million in capital assets, including acquisitions, of which approximately $85 million has been designated as costs associated with the inventory of future prospects. These costs relate to undeveloped land, seismic and facility capacity. In the evaluation of the Company's reserves at December 31, 2006, GLJ estimated future development capital of $9.1 million for proven reserves and $17.1 million for proven plus probable is required to develop its reserves. During the same period West added approximately 10.5 million Boe of proven plus probable reserves.

(i) Internal Finding and Development Cost

West's internally used finding and development cost, since inception, is $24.71 per Boe, based on proven plus probable reserves, including the future capital investment identified in GLJ's reserve report and the future prospect inventory costs of $27 million. Excluding the future prospect inventory costs of $27 million the finding and development cost is $22.16 per Boe.

(ii) 51-101 Compliant Finding and Development Cost

The calculation of finding and development costs under the Canadian Securities Administrators' National Policy Instrument 51-101 excludes the cost of acquisitions and proceeds from dispositions, which for West amount to $50.5 million and $5.8 million respectively. Using the NI 51-101 methodology, West's finding and development cost from inception to December 31, 2006, is $28.09 per Boe for proven reserves and $20.48 per Boe for proven plus probable reserves.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("Management's Discussion and Analysis") is dated and based on information as at March 19, 2007 and is provided by the management of West Energy Ltd. ("West" or the "Company") and prepared in accordance with the requirements of National Instrument 51-102 and Form 51-102F1. It should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2006, included in this Annual Report, the Annual Information Form and the audited annual financial statements of the Company as at and for the year ended December 31, 2006.

The Company's financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Additional Information

The information contained in this Annual Report represents only a portion of the current information available on West Energy Ltd. Readers are encouraged to read West's Annual Information Form dated March 30, 2007, and the Management Information Circular. These documents together with quarterly reports, news releases and corporate presentations are available by visiting the Company's website at www.westenergy.ca. Additional information regarding the Company, including all continuous disclosure documents, can be obtained on SEDAR at www.sedar.com. If you require a hard copy of any of these documents please call the Company's main office number (403)265-5202.

Special Note

Disclosure provided herein in respect of barrels of oil equivalent ("Boe") may be misleading, particularly if used in isolation. A Boe conversion ratio for natural gas of 6 Mcf: 1 Bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalence at the wellhead.

Non-GAAP Measures

Management's Discussion and Analysis contains the term "funds from operations", which should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with GAAP as an indicator of the Company's financial performance. Funds from operations is determined by adding non-cash expenses to the net income or loss for the period, deducting asset retirement expenditures and does not include the change in working capital applicable to operating activities. Management believes that in addition to cash flow from operating activities, funds from operations is a useful supplemental measure as it provides an indication of the results generated by West's principal business activities before the consideration of how such activities are financed. The Company's determination of funds from operations may not be comparable to that reported by other companies. Management's Discussion and Analysis also contains the terms operating netback and corporate netback, which are not considered to be GAAP. Operating netbacks are calculated by deducting royalties and operating costs from revenues and corporate netbacks are calculated by deducting general and administrative and interest expenses from operating netbacks. The Company's determination of operating and corporate netbacks may not be comparable to that reported by other companies.

Evaluation of Effectiveness of Disclosure Controls and Procedures

Management has established and maintains disclosure controls and procedures for the Company in order to provide reasonable assurance that material information relating to the Company is made known to it in a timely manner. The Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the Company's disclosure controls and procedures as of December 31, 2006, and have concluded that the Company's disclosure controls and procedures provide reasonable assurance that material information relating to the Company, including its consolidated subsidiaries and partnership, would be made known to them by others within those entities, particularly during the period in which this report was being prepared.

Internal Controls over Financial Reporting

Management is responsible for the design of internal controls over financial reporting within the Company in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Management has designed the Company's internal controls and procedures over financial reporting as of the end of the period covered by this annual filing and believes the design to be sufficient to provide such reasonable assurance. The design of the internal controls and procedures by their nature have inherent limitations and are restricted due to lack of segregation of duties, caused by a lack of human resources, and the employees and consultants the Company utilizes in its operations are not experts in all areas of their individual responsibility. The Company also utilizes and relies on the services of third party experts to evaluate and provide certain data which is integral to the preparation and reporting of financial information. This information is reviewed by Company personnel for reasonableness however, there is no assurance of the accuracy or completeness of the information. There have been no changes in the Company's internal controls over financial reporting during the year ended December 31, 2006, that have materially affected or are reasonably likely to materially affect the internal controls over financial reporting.

Forward-looking Statements

Certain statements contained in this Annual Report constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Annual Report should not be unduly relied upon. These statements speak only as of the date of this Annual Report. The Company does not intend, and does not assume any obligation, to update these forward-looking statements.

In particular, this Annual Report contains forward-looking statements pertaining to the following:

- *the quantity of reserves;*
- *oil and natural gas production levels;*
- *capital expenditure programs;*
- *projections of market prices and costs;*
- *supply and demand for oil and natural gas;*
- *operating, general and administrative, interest and income tax expenses;*
- *operating and corporate netbacks;*
- *expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development; and*
- *treatment under government regulatory and taxation regimes.*

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Report:

- *volatility in market prices for oil and natural gas;*
- *liabilities and risks inherent in oil and natural gas operations;*
- *uncertainties associated with estimating reserves;*
- *competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *incorrect assessments of the value of acquisitions; and*
- *geological, technical, drilling and processing problems.*

FINANCIAL RESULTS

West recorded net income of $6.2 million ($0.10 per share) for the year ended December 31, 2006, compared to net income of $3.4 million ($0.07 per share) for the year ended December 31, 2005. Funds from operations for 2006 were $35.2 million ($0.58 per share) versus $16.0 million ($0.32 per share) for 2005. Cash flow from operating activities, as determined in accordance with GAAP, was $29.4 million ($0.49 per share) for 2006 and $17.9 million ($0.36 per share) for 2005. Per share amounts are based on the weighted average number of shares outstanding of 60,227,886 for 2006 and 50,287,679 for 2005.

In the fourth quarter of 2006, West recorded a loss of $6,000 ($0.00 per share) compared to net income of $1.1 million ($0.02 per share) for the corresponding period in 2005. For the three months ended December 31, 2006, funds from operations were $6.1 million ($0.10 per share) and for the fourth quarter of 2005 were $5.8 million ($0.11 per share). Cash flow from operating activities, as determined in accordance with GAAP, was $5.1 million ($0.08 per share) for 2006 and $7.6 million ($0.15 per share) for 2005. The above per share amounts are based on the weighted average number of shares outstanding of 62,184,465 for Q4 2006 and 51,976,188 for the corresponding period in 2005.

The changes to the individual amounts affecting the financial results of the Company for the years and quarters ended December 31, 2006 and 2005 are described below.

Revenues, Production and Prices

For the year ended December 31, 2006, oil and gas revenues were $66.9 million from average daily production of 2,754 Boe/d (gas converted at 6 Mcf to 1 barrel of oil equivalent) consisting of 2,218 Bbls/d of oil and NGLs and 3,216 Mcf/d of gas and based on average prices of $69.85 per Bbl of oil and NGLs and $7.54 per Mcf of natural gas. West's production for the year consisted of approximately 81% oil and liquids and 19% natural gas. For the year ended December 31, 2005 oil and gas revenues were $29.5 million representative of average daily production of 1,256 Boe/d (1,015 Bbls of oil and NGLs and 1,447 Mcf of natural gas) and average prices of $64.15 per Bbl of oil and NGLs and $9.54 per Mcf of natural gas. Production in 2005 was approximately 81% oil and liquids and 19% natural gas.

Oil and gas revenues for the fourth quarter of 2006, were $14.7 million compared to $12.0 million for the corresponding period in 2005. Average daily production volumes for Q4, 2006 were 2,791 Boe/d (2,306 Bbls of oil and NGLs and 2,908 Mcf of natural gas) compared to 1,880 Boe/d (1,605 Bbls of oil and NGLs and 1,651 Mcf of natural gas) in the fourth quarter of 2005. Production decreased in Q4, 2006 from Q3, 2006 levels due to reservoir pressure declining below minimum operating pressure which resulted in certain production being shut-in pending increased reservoir pressure. By the fourth quarter of 2006 and early 2007 production was re-established. The Company received average prices of $58.84 per Bbl of oil and NGLs and $7.57 per Mcf of natural gas during the quarter ended December 31, 2006 versus $66.83 and $12.45 respectively, during the quarter ended December 31, 2005.

At the end of 2006, West had shut-in production in the Lodgepole, Violet Grove, Paddy Creek and Pembina East areas pending increased reservoir pressure from the implementation of enhanced oil recovery (EOR) schemes. At Lodgepole, West commenced water injection into the TT pool on December 22, 2006. To expedite the water injection process and increase reservoir pressure, West converted its oil producing well at 01-06-48-09W5 to a water injection well to allow its 14-32-47-09W5 well to be placed back on production in late January, 2007 at approximately 600 Boe/d. Production is expected to increase as reservoir pressures improve. The Company's well at 16-32-47-09W5 is expected to be placed on stream late in the first quarter of 2007 upon approval of a good production practice (GPP) application. At Violet Grove water injection for the SS pool commenced December 15, 2006 and allowed West to recommence production

from its 16-28-48-08W5 and 14-27-48-08W5 wells, which on a combined basis averaged 1,450 Boe/d to West in January, 2007. In addition, water injection commenced at the Violet Grove WW pool and West's 60% well at 05-35-48-08W5 was brought on stream in February, 2007 at 1,200 Boe/d. On January 31, 2007, West received EOR approval for its Paddy Creek water injection project which will support production voidage created by the Nisku KK pool (two wells 1-32 and 11-32-48-9W5 W.I. 50%) and the Nisku V pool (6-28-48-9W5M W.I. 25%). In the GG pool at Pembina East, the EOR project commenced in January, 2007 and allowed 240 Boe/d of production to placed on stream. Production at Crossfire will commence upon installation of facilities late in Q2, 2007.

Additional production increases are dependent upon future drilling successes in the Pembina area and diversification into new prospect areas. The Company has no control over commodity prices and currency exchange rates and therefore cannot predict the prices it will receive for its production. The Company does not have any plans to hedge product prices in 2007.

The following table provides details of revenues for the fourth quarters and the years ended 2006 and 2005:

	Three months ended December 31,		Year ended December 31,	
($000)	2006	2005	2006	2005
Oil and NGLs	$ 12,481	$ 9,871	$ 56,543	$ 23,764
Natural gas	2,024	1,890	8,846	5,037
Gross overrides, processing and salt water disposal	225	199	1,540	663
Total	$ 14,730	$ 11,960	$ 66,929	$ 29,464

Royalties

For the year ended December 31, 2006, royalties averaged $15.33 per Boe or 23.6% of oil and gas revenues compared to royalties of $15.15 per Boe or 24.1% of revenues in 2005. Royalties in the fourth quarter of 2006 were $16.72 per Boe compared $18.33 per Boe in 2005. The Company was eligible and benefited from royalty tax credits and royalty holidays with the discovery of new hydrocarbon pools. West will continue to be eligible for royalty holidays.

Operating Expenses

For 2006 operating costs were $12.5 million or $12.42 per Boe compared to $4.1 million or $8.87 per Boe for 2005. Cost increases in 2006 resulted from human resource shortages and supply and demand issues experienced by the Company and oil and gas industry as a whole. Operating expenses for the last quarter of 2006 were $3.3 million or $12.72 per Boe compared to $1.9 million or $11.10 per Boe.

A large component of West's operating costs at the Paddy Creek battery are fixed costs and as additional production is brought on stream the cost per Boe is expected to decline.

Netbacks

The light oil and high heat content gas production from the Pembina area attract premium prices in the market place and contribute to the operating netbacks the Company receives on its overall production. The Company has no control over commodity prices, which declined in the fourth quarter of 2006 and contributed to slightly lower netbacks experienced for the year from those realized in 2005. For the year ended 2006 operating netbacks (revenues net of royalties and operating costs) averaged $37.31 per Boe versus $38.80 per Boe in 2005. In the fourth quarter of 2006, operating netbacks averaged $27.06 per Boe compared to an average of $38.55 per Boe for the last quarter of 2005.

The decline in the operating netback in the fourth quarter of 2006 was primarily attributed to declining commodity prices.

Corporate netbacks (operating netbacks less general and administrative and interest expenses) averaged $33.62 per Boe in 2006 compared to $33.96 per Boe for 2005. In the fourth quarter of 2006 and 2005 were $23.02 and $33.26, respectively.

	Three months ended December 31,				Year ended December 31,			
		2006		2005		2006		2005
Prices								
Natural gas (per Mcf)	$	7.57	$	12.45	$	7.54	$	9.54
Crude oil and NGLs (per Bbl)	$	58.84	$	66.83	$	69.85	$	64.15
Revenues (per Boe)	$	56.50	$	67.98	$	65.06	$	62.82
Royalties (per Boe)	$	16.72	$	18.33	$	15.33	$	15.15
Operating costs (per Boe)	$	12.72	$	11.10	$	12.42	$	8.87
Operating netback (per Boe)	$	27.06	$	38.55	$	37.31	$	38.80
General and administrative (per Boe)	$	2.97	$	3.10	$	2.84	$	3.48
Interest expense (per Boe)	$	1.07	$	2.19	$	0.85	$	1.36
Corporate netback (per Boe)	$	23.02	$	33.26	$	33.62	$	33.96

General and Administrative

For the year ended December 31, 2006, general and administrative expenses, net of capitalized costs, were $2.8 million ($2.84 per Boe) compared to $1.6 million ($3.48 per Boe) for 2005. Increased costs are primarily due to additional staff requirements and increased insurance coverage. Capitalized general and administrative costs for the year ended December 31, 2006 were $0.8 million and $0.9 million for 2005.

For the fourth quarter of 2006 general and administrative expenses, net of capitalized costs, were $0.8 million ($2.97 per Boe) and $0.5 million ($3.10 per Boe) for Q4, 2005. Capitalized general and administrative costs related to exploration and development activities for the three months end December 31, 2006 were $0.2 million and $0.4 million for the corresponding period in 2005.

Expected increases in drilling activity and production in 2007 will require additional human resources, and together with inflationary pressures will increase future general and administrative costs. As additional production comes on stream throughout 2007, general and administrative costs on a per Boe basis, are expected to decline from those realized in 2006.

Interest Expense

West incurred interest expense of $0.9 million in 2006 and $0.6 million in 2005 as the Company utilized its borrowing facilities to finance certain aspects of its capital expenditure program, primarily expenditures related to land and facility acquisitions. For the quarters ended December 31, 2006 and 2005, interest expense was $0.3 million and $0.4 million respectively.

West expects to incur interest expense in 2007 and the amount of interest will be dictated by draw downs on its credit facilities to fund future capital expenditures, interest rates, and repayments of indebtedness from funds from operations.

Stock Based Compensation Expense

Stock based compensation expense represents the amortization of the fair value of stock options and warrants, issued to employees, directors and consultants, over the vesting period of the options and warrants. The Company recorded compensation expense of $1.5 million for the year ended 2006 compared to $1.2 million in 2005. In Q4, 2006, stock based compensation expense was $0.1 million compared to $0.4 million in the fourth quarter of 2005. During 2006, the Company capitalized stock based compensation of $0.7 million.

Depletion, Depreciation and Accretion

For the year ended December 31, 2006, depletion, depreciation and accretion expense was $28.9 million ($28.80 per Boe) compared to $10.3 million ($22.45 per Boe) for the year ended 2005. Depletion, depreciation and accretion expense in Q4, 2006 was $8.4 million ($32.73 per Boe) versus $4.5 million ($25.99 per Boe) in Q4, 2005. The increase in the Boe rate in the fourth quarter of 2006 relates to the application of differences between in-house reserve evaluations and the evaluation of West's independent reservoir engineers. Facilities and infrastructure accounted for 50% of the Company's capital expenditures in 2006 for which there were no attributable reserve additions but were necessary to produce discovered reserves. As a result the depletion and depreciation rate per Boe increased in 2006 from previous periods.

Drilling activity, the construction of the Paddy Creek battery and infrastructure have contributed to the amount of the asset retirement obligation. Accretion expense relating to the asset retirement obligation was $214,000 in 2006 and $93,000 for 2005 and has been included in depletion, depreciation and accretion expense.

Income Taxes

The Company did not incur current taxes in either 2006 or 2005, but did incur Large Corporation Tax in 2005 which was eliminated effective January 1, 2006. Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The following table summarizes West's estimated tax pools, by classification, as at December 31, 2006 and 2005:

($million)	2006	2005
Canadian exploration expenses	49	29
Canadian development expenses	13	4
Canadian oil and gas property expenses	15	22
Undepreciated capital costs	64	47
Share issue costs	7	9
Non-capital losses	6	9
Total	154	120

Tax pools at December 31, 2006, are expected to defer current income tax expense until 2008, which may be deferred by future capital expenditures and tax planning.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2006, West had a working capital deficiency of $18.5 million, including $13.6 million of bank debt. The Company has credit facilities of $55.0 million with a Canadian bank consisting of a $45.0 million revolving operating demand loan which bears interest at the bank's prime rate plus 0.10% per annum and a $10.0 million non-revolving development demand loan which bears interest at the bank's prime rate plus 0.35% per annum. The assets of the Company are pledged as security for amounts drawn on the credit facility under a general security agreement. The credit facility is scheduled to be reviewed by the financial institution in the second quarter of 2007.

In November, 2006, the Company completed a private placement of 4.1 million common shares issued on a flow-through basis for gross proceeds of $30.0 million ($28.0 million net of issue costs). The net proceeds of this offering were used to temporarily reduce bank indebtedness, which has been, or will be redrawn and applied to fund the Company's capital expenditure program for 2007. The directors and officers of the Company did not participate in the private placement. The Company's capital expenditure program for 2007, including its commitment related to its November, 2006 flow-through share offering, is expected to be limited to its funds from operations for the year.

Capital Expenditures

For the year ended December 31, 2006, the Company's capital expenditures were $82.1 million compared to $91.9 million for the year ended 2005. During the three months ended December 31, 2006, West incurred $21.8 million of capital expenditures compared to $36.3 million during the same period in 2005. In 2006 and 2005, West participated in 26 (16.45 net) and 17 (8.26 net) wells respectively of which 7 (4.11 net) were drilled in the fourth quarter of 2006 and 4 (2.17 net) were drilled in the fourth quarter of 2005. The Pembina Nisku fairway was the focus of West's capital expenditure program for 2006 and 2005. In 2007, the Company will continue with its program in the Pembina area and expects to diversify its program into other areas.

Capital expenditures for the fourth quarters and the years ended 2006 and 2005 were as follows:

	Three months ended December 31,		Year ended December 31,	
($000)	**2006**	2005	**2006**	2005
Land	**$ 296**	$ 682	**$ 3,040**	$ 9,994
Seismic	**1,302**	(153)	**2,080**	4,656
Drilling and intangibles	**9,893**	10,615	**41,337**	26,948
Facilities and equipment	**10,070**	24,822	**34,736**	49,290
Capitalized general and administrative	**214**	210	**844**	853
Furniture and equipment	**6**	98	**60**	129
Total	**$ 21,781**	$ 36,274	**$ 82,097**	$ 91,870

Property Dispositions

During 2006, the Company disposed of a non-core property for net proceeds of $10.3 million. Prior to the disposition this property contributed approximately 40 Boe/d to the Company's production. The Company disposed of a minor property in 2005 for proceeds of $0.3 million.

ACCOUNTING POLICIES

There have been no change in accounting policies since the Company's last fiscal year end.

Critical Accounting Estimates

Full Cost Accounting Guideline AcG - 16: For purposes of financial statements, companies are required to review the carrying value of their assets relative to their recoverable amount. Under the Full Cost Accounting Guideline AcG - 16 the guideline amends the ceiling test calculation to be a two part process. The first part, the recognition of impairment, is determined by comparing the carrying amount of petroleum and natural gas properties and equipment to the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Company's contract prices and quality differentials. If there is impairment, the second part of the calculation would measure the magnitude of the impairment by comparing the carrying amount of petroleum and natural gas properties and equipment to the estimated net present value of future cash flows from proved plus probable reserves. A risk free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the future cash flows would be recorded as a permanent impairment and charged as additional depletion, depreciation and accretion expense in the statement of operations.

Petroleum and Natural Gas Reserves: All of West's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineers. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing or production levels.

Depletion, Depreciation and Accretion Expense: The Company uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion and depreciation expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment which would be included in depletion and depreciation expense.

SHARE CAPITAL DATA

The Company is authorized to issue an unlimited number of common voting shares. Share capital at December 31, 2006, is detailed in note 7 of the Company's December 31, 2006, consolidated financial statements. As at March 19, 2007, there were 64,717,473 shares issued and outstanding and 4,642,000 warrants and options issued and unexercised.

OFF BALANCE SHEET ARRANGEMENTS

The Company does not have any special purpose entities nor is it party to any arrangement that would be excluded from the balance sheet.

RELATED PARTY TRANSACTIONS

In 2006, the Company paid $28,665 of fees to the law firm of which the Corporate Secretary is a partner. Of these fees, $19,070 was charged to earnings and $9,595 was charged to share capital as share issue costs. In 2005, the Company paid $164,491 of fees to the law firm of which $32,063 was charged to earnings and $132,428 was charged to share capital as share issue costs.

BUSINESS RISKS

There are inherent risks in the exploration for and development of oil and natural gas. Operational risks include finding economic oil and natural gas reserves, production once the reserves are discovered, cost of materials and services, access to production facilities and transportation, and the ability to attract and retain, at a reasonable cost, the best human resources available. The procurement of equipment from manufacturers during a period of time when the oil and gas industry is reaching capacity causes delays in completing projects on time. This was evident with the delays West experienced with the construction of its Pembina battery facilities and ongoing projects in the Pembina area.

Financial risks that are not within West's control include the fluctuation in commodity prices, foreign exchange rates, provincial and federal regulations, royalties, taxes and interest rates. The well licensing process for sour operations is an onerous and costly exercise for operators and can take up to six months of resident consultations and applications to obtain a drilling license. The Company has not entered into crude oil swap contracts to hedge against a downturn in commodity prices.

The Company endeavors to manage certain risks by focusing on controlling finding and development costs, operating costs, and general and administrative expenses. West's strategy of focusing on core geophysical areas and geological targets results in controlling capital risk.

The Company also faces environmental risks associated with the pollution of ground, air and water. The Pembina Nisku play contains sour gas with an H_2S content of up to 30%. The safety of the area residents is of utmost importance and the aspects of dealing with sour operations are more regulated than other operations in western Canada. The Company believes these risks are manageable and adheres to and promotes the highest standards of safety and environmental protection in all of its operations. Obtaining approvals from the AEUB and responding to resident concerns is a lengthy and costly process. The Company undertakes consultations with Pembina area residents to advise them of the risks associated with sour gas operations and the emergency response procedures that the Company has in the unlikely event such an emergency should occur. A comprehensive insurance program is maintained to mitigate risks and protect against significant losses. This program protects against losses from pollution, well blowouts, interruptions to operations and other forms of asset damage.

SELECTED ANNUAL INFORMATION

The following table sets forth selected financial information for each of the Company's years ended December 31, 2006, 2005 and 2004.

($000, except per share amounts)	December 31, 2006	December 31, 2005	December 31, 2004
Oil and gas revenues	$ 66,929	$ 29,464	$ 18,475
Net income (loss)	$ 6,244	$ 3,357	$ (817)
Per share	$ 0.10	$ 0.07	$ (0.02)
Basic and diluted	$ 0.10	$ 0.06	$ (0.02)
Funds from operations	$ 35,178	$ 15,993	$ 8,956
Per share	$ 0.58	$ 0.32	$ 0.22
Basic and diluted	$ 0.55	$ 0.29	$ 0.19
Cash flow from operating activities	$ 29,438	$ 17,858	$ 10,135
Per share	$ 0.49	$ 0.36	$ 0.25
Basic and diluted	$ 0.46	$ 0.32	$ 0.24
Total assets	$ 233,191	$ 180,809	$ 99,346
Total long-term financial liabilities	$ –	$ –	$ –
Shareholders' equity	$ 177,636	$ 142,236	$ 72,816

CONTRACTUAL OBLIGATIONS

The Company is committed to office lease payments to the end of May, 2009 in the total amount of $0.6 million.

In November, 2006, the Company issued 4.1 million shares on a flow-through basis for gross proceeds of $30.0 million and effective December 31, 2006, renounced $30.0 million if capital expenditures to the subscribers of the flow-through shares. At the end of December, 2006, the Company had incurred $1.3 million of Canadian exploration expenditures and has plans to incur a minimum of $28.7 of Canadian exploration expenditures in 2007.

The Company's credit facilities include a revolving operating demand loan, which is subject to an annual review.

ADDITIONAL INFORMATION

Further information regarding the Company, including the Company's Annual Information Form, can be accessed under the Company's public filings found on SEDAR at www.sedar.com. Information can also be obtained by contacting the Company at Suite 600, 333 - 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

SELECTED QUARTERLY INFORMATION

The following table sets forth selected information of the Company for each financial quarter for the period January 1, 2005 to December 31, 2006.

	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Sales Volumes								
Oil and NGLs (Bbls/d)	2,306	2,531	2,481	1,542	1,605	897	772	778
Natural gas (Mcf/d)	2,908	3,224	4,628	2,093	1,651	1,475	1,360	1,300
Barrels of oil equivalent (Boe/d)	2,791	3,068	3,252	1,891	1,880	1,143	999	995
Financial (000, except per share amounts)								
Oil and gas revenues	$ 14,730	$20,879	$19,855	$11,465	$ 11,960	$ 7,212	$ 5,400	$ 4,892
Funds from operations	$ 6,058	$12,529	$10,621	$ 5,970	$ 5,797	$ 4,416	$ 3,215	$ 2,598
Per Share								
Basic	$ 0.10	$ 0.21	$ 0.18	$ 0.10	$ 0.11	$ 0.09	$ 0.07	$ 0.05
Diluted	$ 0.09	$ 0.20	$ 0.17	$ 0.08	$ 0.10	$ 0.08	$ 0.06	$ 0.05
Cash flow from operations	$ 5,095	$11,166	$10,956	$ 2,221	$ 7,586	$ 4,086	$ 4,644	$ 1,542
Per Share								
Basic	$ 0.08	$ 0.19	$ 0.18	$ 0.04	$ 0.15	$ 0.08	$ 0.09	$ 0.03
Diluted	$ 0.08	$ 0.18	$ 0.17	$ 0.03	$ 0.13	$ 0.07	$ 0.09	$ 0.03
Net income (loss)	$ (6)	$ 3,531	$ 2,278	$ 441	$ 1,098	$ 769	$ 781	$ 709
Per Share								
Basic	$ 0.00	$ 0.06	$ 0.04	$ 0.00	$ 0.02	$ 0.01	$ 0.02	$ 0.01
Diluted	$ 0.00	$ 0.06	$ 0.04	$ 0.00	$ 0.02	$ 0.01	$ 0.01	$ 0.01
Capital expenditures	$ 21,781	$22,948	$12,033	$25,337	$ 36,274	$ 29,296	$ 9,970	$16,330
Shares outstanding	64,212	60,041	60,021	58,958	58,661	51,655	51,129	48,602
Per Unit Information								
Prices								
Oil and NGLs ($/Bbl)	$ 58.84	$ 76.94	$ 76.32	$ 64.63	$ 66.83	$ 71.15	$ 58.96	$ 55.45
Natural gas ($/Mcf)	$ 7.57	$ 6.94	$ 6.49	$ 10.79	$ 12.45	$ 10.07	$ 7.85	$ 6.93
Oil equivalent ($/Boe)	$ 56.50	$ 70.58	$ 67.45	$ 64.65	$ 67.98	$ 68.84	$ 56.26	$ 52.42
Operating netback ($/Boe)	$ 27.06	$ 44.46	$ 39.32	$ 37.42	$ 38.55	$ 47.10	$ 36.89	$ 31.45
Wells Drilled								
Gross	7	7	5	7	4	4	–	9
Net	4.11	4.83	2.09	5.42	2.17	1.31	–	4.78
Drilling Results								
Oil	1	5	1	2	1	1	–	3
Natural gas	2	1	3	1	2	1	–	4
Service	4	–	–	1	–	2	–	–
Dry	–	1	1	3	1	–	–	2
Total	7	7	5	7	4	4	–	9

The trends over our most recent quarters are discussed throughout the Management Discussion and Analysis. The objective for 2007 is to increase shareholder value, increase production and associated revenues, control costs with a positive impact to net income and expand its exploration efforts for sweet oil and natural gas in a new project area where West has shot extensive 3D seismic and acquired lands.

MANAGEMENT'S REPORT

To the Shareholders of West Energy Ltd.

The reliability and integrity of the accompanying consolidated financial statements of West Energy Ltd. and all other financial and operating information contained in this report are the responsibility of management. The consolidated financial statements have been prepared in accordance with accounting policies detailed in the notes to the consolidated financial statements and in accordance with Canadian generally accepted accounting principles and contain estimates based on management's informed judgments. Management believes these estimates are properly reflected in the accompanying consolidated financial statements.

The Company's systems of internal controls have been designed and maintained to provide reasonable assurance that assets are properly safeguarded and that the financial accounting systems and records are properly maintained to provide relevant, timely and reliable information to management and shareholders. The design of the internal controls and procedures by their nature have inherent limitations and are restricted due to lack of segregation of duties, caused by a lack of human resources, and the employees and consultants the Company utilizes in its operations are not experts in all areas of their individual responsibility. The Company also utilizes and relies on the services of third party experts to evaluate and provide certain data which is integral to the preparation and reporting of financial information. This information is reviewed by Company personnel for reasonableness however, there is no assurance of the accuracy or completeness of the information. There have been no changes in the Company's internal controls over financial reporting during the year ended December 31, 2006, that have materially affected or are reasonably likely to materially affect the internal controls over financial reporting.

External auditors, appointed by the shareholders, have independently examined the consolidated financial statements. They have performed an audit, which included such tests as they deemed necessary to enable them to express an opinion on these consolidated financial statements.

The Audit Committee, consisting of independent members of the Board of Directors, has reviewed these consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

KEN MCCAGHERTY
President and Chief Executive Officer

R.K. (RICK) JAGGARD
Vice President Finance and Chief Financial Officer

Calgary, Alberta

March 19, 2007

AUDITORS' REPORT

To the Shareholders of West Energy Ltd.

We have audited the consolidated balance sheets of West Energy Ltd. as at December 31, 2006 and 2005 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP
Chartered Accountants

Calgary, Alberta

March 19, 2007

CONSOLIDATED BALANCE SHEETS

(000s)	December 31, 2006	December 31, 2005
ASSETS		
Current assets		
Cash and cash equivalents	$ –	$ 5,486
Accounts receivable	20,037	7,488
Prepaid expenses and deposits	1,305	1,026
	21,342	14,000
Property, plant and equipment (note 3)	197,166	152,126
Goodwill	14,683	14,683
	$ 233,191	$ 180,809
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness (note 4)	$ 13,599	$ –
Accounts payable and accrued liabilities	26,267	25,574
	39,866	25,574
Asset retirement obligation (note 5)	3,438	2,441
Future income taxes (note 6)	12,251	10,558
	55,555	38,573
Shareholders' equity		
Share capital (note 7)	165,497	138,221
Contributed surplus (note 7)	3,938	2,058
Retained earnings	8,201	1,957
	177,636	142,236
	$ 233,191	$ 180,809

Commitments (notes 7(a) and 11)

See accompanying notes to financial statements.

Approved on behalf of the Board:

MICHAEL A. COLUMBOS
Director

LARRY G. EVANS
Director

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS

(000s, except per share amounts)	Years ended December 31, 2006	2005
Revenue		
Oil and gas revenues	$ 66,929	$ 29,464
Royalties	(15,410)	(6,946)
	51,519	22,518
Interest and other income	–	114
	51,519	22,632
Expenses		
Operating	12,478	4,068
General and administrative	2,849	1,597
Interest on bank loans	866	622
Stock based compensation expense (note 7)	1,515	1,161
Depletion, depreciation and accretion	28,946	10,293
	46,654	17,741
Income before income taxes	4,865	4,891
Income taxes (note 6)		
Current	–	197
Future (reduction)	(1,379)	1,337
	(1,379)	1,534
Net income for the year	6,244	3,357
Retained earnings (deficit), beginning of year	1,957	(1,400)
Retained earnings, end of year	$ 8,201	$ 1,957
Net income per share:		
Basic	$ 0.10	$ 0.07
Diluted	$ 0.10	$ 0.06
Weighted average common shares outstanding	60,228	50,288
Diluted shares outstanding	64,394	55,107

See accompanying notes to financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000s)	Years ended December 31, 2006	2005
Operating activities		
Net income for the year	$ 6,244	$ 3,357
Items not affecting cash:		
Depletion, depreciation and accretion	28,946	10,293
Stock based compensation expense	1,515	1,161
Future income taxes (reduction)	(1,379)	1,337
Gain on sale of investment	–	(98)
Asset retirement costs incurred	(148)	(57)
	35,178	15,993
Change in non cash working capital (note 9)	(5,740)	1,865
	29,438	17,858
Financing activities		
Issue of share capital, net of issue costs	29,653	63,449
Proceeds from bank loan	13,599	37,145
Repayment of bank loan from proceeds from share issue	–	(37,145)
Change in non-cash working capital (note 9)	(73)	13
	43,179	63,462
Investing activities		
Property, plant and equipment	(82,097)	(91,870)
Proceeds from property dispositions	10,316	308
Proceeds from disposition of investment	–	98
Change in non cash working capital (note 9)	(6,322)	5,994
	(78,103)	(85,470)
Decrease in cash and cash equivalents	(5,486)	(4,150)
Cash and cash equivalents, beginning of year	5,486	9,636
Cash and cash equivalents, end of year	$ –	$ 5,486
Supplementary information		
Interest received	$ 17	$ 75
Interest paid	$ 883	$ 681
Taxes paid	$ 145	$ 63

See accompanying notes to financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2005 and 2006 – Amounts expressed in thousands of dollars except where noted ?

West Energy Ltd. (the "Company") was incorporated under the Business Corporations Act (Alberta) on December 9, 2002. The Company's principal business activity is the exploration, exploitation, development and production of petroleum and natural gas reserves in the Province of Alberta. In March, 2004, the Company acquired its interest in Rubicon Energy Corporation ("Rubicon"). On September 30, 2004, the Company acquired Rio Alto Resources International Inc. ("Rio") by way of a reverse takeover.

1. Basis of presentation

(A) ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada and include the accounts of the Company and its subsidiaries.

2. Significant accounting policies

(A) FULL COST ACCOUNTING

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

The carrying value of the Company's property, plant and equipment is reviewed each reporting period to determine that the carrying value is recoverable and does not exceed the fair value of the properties. Under Canadian accounting standards, the ceiling test calculation is a two part process. The first part, the recognition of impairment, is determined by comparing the carrying amount of petroleum and natural gas properties and equipment to the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Company's contract prices and quality differentials. If there is impairment, the second part of the calculation would measure the magnitude of the impairment by comparing the carrying amount of petroleum and natural gas properties and equipment to the estimated net present value of future cash flows from proved plus probable reserves. A risk free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of the future cash flows would be recorded as a permanent impairment and charged as additional depletion and depreciation expense in the statement of operations. Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

Capitalized costs, together with estimated future capital costs associated with proven reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proven reserves of petroleum and natural gas as determined by independent reservoir engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproven properties, net of impairments, are excluded from the depletion and depreciation calculation.

Other assets, which are comprised of office equipment and furniture and fixtures, are recorded at cost and are depreciated over their useful life on a declining balance basis at rates ranging from 20% to 30%.

(B) ASSET RETIREMENT OBLIGATION

The Company recognizes the fair value of an asset retirement obligation in the period it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The fair value is determined through a review of engineering studies, industry guidelines, and management's estimate on an area by area basis. The liability is subsequently adjusted due to the passage of time, and is recognized as accretion expense in the statement of operations. The liability is subsequently adjusted for revisions in either the timing or the amount of the original estimated cash flows associated with the liability. Actual restoration expenditures are charged to the accumulated obligation to the extent of the liability recorded.

(C) STOCK BASED COMPENSATION

The Company's stock based compensation plans are described in note 7.

The Company recognizes compensation expense, with a corresponding increase to contributed surplus, based on the fair value of the options and warrants granted under the Company's stock based compensation plans over the vesting period of the grant. The Company uses a Black-Scholes option pricing model to determine the fair value of options and warrants at the date of grant. As the options or warrants are exercised, the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(D) FUTURE INCOME TAXES

The Company accounts for future income taxes using the liability method. Under this method, future income taxes and liabilities are measured based upon temporary differences between the carrying amounts of assets and liabilities and their tax basis. Future tax assets and liabilities are measured using enacted or substantially enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse.

(E) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion, depreciation and amortization of petroleum and natural gas assets, the asset retirement obligation and stock based compensation are based on estimates. The cost recovery ceiling test is based on estimates of reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(F) PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in the period. Diluted per share amounts are calculated based on the treasury-stock method, which assumes that any proceeds obtained on exercise of in-the-money options and warrants plus the unamortized stock based compensation cost would be used to purchase common shares at the average market value during the period. The weighted average number of shares outstanding is then adjusted by the net change.

(G) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deductions when the tax pools are renounced.

(H) CASH AND CASH EQUIVALENTS

The Company considers deposits in banks, certificates of deposit and short-term investments with original maturities of three months or less as cash and cash equivalents. Bank borrowings are considered to be financing activities.

(I) INTEREST IN JOINT VENTURES

Substantially all of the Company's oil and gas exploration and development activities are conducted jointly with others, and accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(J) GOODWILL

Goodwill represents the excess purchase price over the fair value of identifiable assets and liabilities acquired in a business combination. Goodwill is subject to an annual impairment review, and more frequently as economic events dictate. To assess impairment, the fair value of the Company is determined and compared to the book value of the Company. If the fair value of the Company is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the individual assets and liabilities from the fair value of the Company to determine the implied fair value of goodwill and comparing that amount to the book value of the Company's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. Should an impairment provision be required, it will be charged to earnings in the period of impairment. Goodwill is not amortized.

(K) REVENUE RECOGNITION

Crude oil and natural gas revenues are recognized in earnings when title passes from the Company to its customer.

3. Property, plant and equipment

	December 31, 2006		
($000s)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and equipment	$ 244,471	$ (47,459)	$ 197,012
Furniture and equipment	307	(153)	154
Total	$ 244,778	$ (47,612)	$ 197,166

	December 31, 2005		
($000s)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties and equipment	$ 170,760	$ (18,789)	$ 151,971
Furniture and equipment	246	(91)	155
Total	$ 171,006	$ (18,880)	$ 152,126

During the year ended December 31, 2006, the Company capitalized general and administration and stock based compensation costs of $1.6 million (2005 - $0.9 million) in addition to $0.3 million (2005 - nil) for the future income tax effect of capitalizing stock based compensation, which are included in property, plant and equipment. The cost of unproved properties excluded from the depletion base as at December 31, 2006 was $16.8 million (2005 - $23.2 million). Drilling in progress at December 31, 2006 of $6.2 million (2005 - $26.3 million) was excluded from the depletable base. Estimated future development costs associated with proved reserves of $10.2 million (2005 - $16.8 million) are included in the depletable base.

The future commodity prices used in the ceiling test were based on December 31, 2006 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the ceiling test:

Year	West Texas Intermediate ($U.S./Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	AECO Gas Price ($Cdn/MMBTU)	Edmonton Butane ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Pentanes Plus ($Cdn/Bbl)
Forecast						
2007	62.00	70.25	7.20	56.25	45.00	71.75
2008	60.00	68.00	7.45	50.25	43.50	69.25
2009	58.00	65.75	7.75	48.75	42.00	67.00
2010	57.00	64.50	7.80	47.75	41.25	65.75
2011	57.00	64.50	7.85	47.75	41.25	65.75
2012	57.50	65.00	8.15	48.00	41.50	66.25
2013	58.50	66.25	8.30	49.00	42.50	67.50
2014	59.75	67.75	8.50	50.25	43.25	69.00
2015	61.00	69.00	8.70	51.00	44.25	70.50
2016	62.25	70.50	8.90	52.25	45.00	72.00
2017	63.50	71.25	9.10	53.00	46.00	73.25
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

The Company has determined that an impairment provision was not required at December 31, 2006 and 2005.

4. Bank facilities

The Corporation has credit facilities of $55.0 million with a Canadian bank consisting of a $45.0 million revolving operating demand loan which bears interest at the bank's prime rate plus 0.10% per annum and a $10.0 million non-revolving development demand loan which bears interest at the bank's prime rate plus 0.35% per annum. The assets of the Corporation are pledged as security for amounts drawn on the credit facility under a general security agreement. At December 31, 2006, the Company had drawn $13.6 million on its revolving operating loan. At February 28, 2007, the Company had drawn $21.3 million on its revolving operating loan. The Corporation has issued an irrevocable letter of guarantee in the amount of $146,700 to a pipeline company as a guarantee for future services. The credit facility is scheduled to be reviewed by the financial institution in the second quarter of 2007.

5. Asset retirement obligation

The total future asset retirement obligation was estimated by management based on the expected cost to abandon and restore the well and facility sites and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of its asset retirement obligation to be $3.4 million as at December 31,

2006, based on the total undiscounted future liability of $5.3 million. These costs are expected to be incurred between 2007 and 2016. The Company used a credit adjusted risk free rate of 8.0% and an inflation rate of 2% to calculate the present value of the asset retirement obligation. Property, plant and equipment were increased by a similar amount.

The following table sets forth the changes in the asset retirement obligation:

($000s)	December 31, 2006	December 31, 2005
Balance beginning of year	$ 2,441	$ 1,156
Increase in obligation for wells drilled and facilities constructed	989	1,405
Current period accretion	214	93
Disposed properties	(58)	(156)
Costs incurred in the year	(148)	(57)
Balance end of year	$ 3,438	$ 2,441

6. Future income taxes

(A) The components of the future income tax liability are as follows:

($000s)	December 31, 2006	December 31, 2005
Net book value of property, plant and equipment in excess of tax value	$ 17,397	$ 15,120
Non-capital losses	(1,893)	(1,458)
Share issue costs and other	(2,244)	(2,277)
Asset retirement obligation	(1,009)	(827)
Total	$ 12,251	$ 10,558

Non-capital losses of $1.1 million expire in 2009 and $5.3 million expire in 2014.

(B) The provision for income taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 34.5% (2005 - 37.6%) to the income before income taxes for the periods as follows:

	Years ended December 31,	
($000s)	2006	2005
Income before taxes	$ 4,865	$ 4,891
Expected income tax provision	$ 1,678	$ 1,839
Non-deductible crown royalties, net of ARTC	811	537
Resource allowance	(688)	(705)
Non-deductible stock based compensation expense	523	437
Realization of previously unrecognized non-capital losses	(1,500)	(771)
Enacted rate change	(2,216)	–
Other	13	–
	(1,379)	1,337
Capital taxes	–	197
Total	$ (1,379)	$ 1,534

7. Share capital

(A) COMMON SHARES

(i) Authorized

Unlimited number of common voting shares.

(ii) Issued and outstanding

($000s, except share amounts)	Number of Shares	Amount
Balance, December 31, 2004	48,602,408	$ 73,015
Issued during the year		
- Adjustment to number of shares issued on Rio transaction	(1,436)	90
- Public offering for cash	6,820,000	55,924
- Private placement of flow-through shares for cash	1,600,000	10,000
- Exercise of options and performance warrants for cash	1,415,001	1,547
- Exercise of warrants and transfer of warrant proceeds for cash	225,000	191
- Share issue costs	–	(4,292)
- Contributed surplus associated with exercise of warrants and options	–	292
- Tax effect of share issue costs	–	1,454
Balance, December 31, 2005	58,660,973	138,221
Issued during the year		
- Public placement of flow-through shares for cash	4,138,000	30,000
- Exercise of options for cash	213,500	466
- Exercise of performance warrants for cash	1,200,000	1,200
- Share issue costs, net of tax effect	–	(1,406)
- Contributed surplus associated with exercise of warrants and options	–	378
- Tax effect of flow-through shares renounced	–	(3,362)
Balance, December 31, 2006	**64,212,473**	**$ 165,497**

Basic earnings per share is computed by dividing the net earnings available to common shareholders by the weighted average number of common shares outstanding. Diluted earnings per common share is calculated using the treasury stock method to determine the dilutive effect of stock options. The treasury stock method assumes that the proceeds received from the exercise of "in the money" stock options are used to repurchase common shares at the average market price during the period. At December 31, 2006, 325,000 (2005 - 1,473,000) options were not in the money options and excluded from determining the dilutive effect of stock options.

In November, 2006, the company issued 4.1 million shares on a flow-through basis for gross proceeds of $30.0 million and effective December 31, 2006, renounced $30.0 million of capital expenditures to the subscribers of the flow-through shares. At the end of December, 2006, the Company had incurred $1.3 million of Canadian exploration expenditures and has plans to incur a minimum of $28.7 million of Canadian exploration expenditures by December 31, 2007.

(B) STOCK BASED COMPENSATION PLANS

(i) Performance common share purchase warrants

The Company reserved for issuance performance common share purchase warrants ("performance warrants") to purchase up to 5,000,000 common shares. The Company granted 4,500,000 performance warrants in 2003 and 500,000 in 2004. On November 8, 2004, 100% of the performance common share purchase warrants vested. In 2006, 1,200,000 (2005 - 825,000) were exercised. Each performance warrant entitles the holder to acquire one common share at a price of $1.00 until November 7, 2008.

The fair value of the 5,000,000 performance warrants granted was $907,200 based on the date of grant.

(ii) Options

The Corporation has a stock option plan for its directors, officers, employees and consultants which provides options to purchase up to a rolling maximum number of common shares equal to 10% of the issued and outstanding shares of the Corporation. In accordance with the Corporation's stock option plan the exercise price of the options is equal to the volume weighted average trading price of the common shares for the five (5) trading days prior to the date of grant and have a maximum term of five years. The vesting provisions of options are determined by the Board of Directors at the time of the grant. The options are generally exercisable one-third on each of the three following anniversary dates of the grant.

In June, 2006 the Board of Directors approved the cancellation of 623,000 options previously granted between July 1, 2005 and April 6, 2006 at exercise prices ranging from $4.75 to $7.80. These options were reissued at an exercise price of $4.13, vest over a three year period commencing June 23, 2006 and expire on June 23, 2011. In addition, the Board of Directors approved a change in the exercise price of 465,000 options to $4.13 with no other changes in terms and conditions. These options were previously granted between December 22, 2004 and November 2, 2005 at exercise prices ranging from $4.60 to $6.75.

The fair value of the 1,673,000 options granted during 2006 was $3,276,252 on the date of grant using the Black-Scholes option pricing model with the following assumptions: average risk free rate of 4.43%, average expected life of 3 years, expected volatility of 54% and no expected dividends. The fair value of the 2,078,000 options granted during 2005 was $4,449,444 on the date of grant using the Black-Scholes option pricing model with the following assumptions: average risk free rate of 3.05%, average expected life of 3 years, expected volatility of 51% and no expected dividends.

During the year ended December 31, 2006, 213,500 options were exercised at prices between $1.00 and $5.54 per option.

At December 31, 2006, the Company had 4,411,500 stock options outstanding for which shares have been reserved.

	Weighted Average Exercise Price	Quantity
Balance, December 31, 2004	$ 1.00	2,475,000
Issued	5.81	2,078,000
Exercised	1.23	(590,001)
Forfeited	2.14	(261,666)
Balance, December 31, 2005	4.59	3,701,333
Issued and repriced	4.50	2,296,000
Exercised	2.15	(213,500)
Forfeited	6.18	(1,372,333
Balance, December 31, 2006	**$ 3.98**	**4,411,500**

(iii) Common share purchase warrants

Financing Warrants

In January, 2004, the Company agreed to grant 500,000 common share purchase warrants to a director of the Company in consideration for providing a guarantee in respect of a demand loan bridge facility. Each common share purchase warrant entitles the holder to purchase one common share at a price of $1.00 per share on or before March 3, 2007. The fair value of the common share purchase warrants granted was $36,128 based on the date of grant using the Black-Scholes option pricing model with the following assumptions: average risk-free rate of 2.50%, average expected life of 3 years, expected volatility of 1% and no expected dividends.

On March 1, 2007, all 500,000 financing warrants were exercised.

(iv) Options and Warrants Outstanding

A summary of the options and warrants outstanding at December 31, 2006 is as follows:

	Options and Warrants Outstanding			Options and Warrants Exercisable	
Exercise prices ($)	Number (000)	Weighted Average Exercise Price ($)	Weighted Average Remaining Contractual Life (years)	Number (000)	Weighted Average Remaining Contractual Life (years)
Performance Warrants					
1.00	2,800	1.00	1.8	2,800	1.8
Financing Warrants					
1.00	500	1.00	0.2	500	0.2
Options					
1.00	150	1.00	1.8	150	1.8
1.75	757	1.75	2.4	757	2.4
4.10	500	4.10	3.4	333	3.4
4.13	1,879	4.13	4.2	188	4.2
4.52	250	4.52	4.6	–	4.6
5.06	21	5.06	4.9	–	4.9
5.22	130	5.22	4.8	–	4.8
5.54	400	5.54	3.0	268	3.0
6.15	100	6.15	3.6	33	3.6
6.70	225	6.70	3.7	75	3.7
	4,412	3.98	3.6	1,803	2.8
Total	7,712	2.70	2.9	5,103	2.2

(C) CONTRIBUTED SURPLUS

($000s)	Amount
Balance, December 31, 2004	$ 1,189
Current year stock based compensation	1,161
Allocated to share capital on exercise of options and warrants	(292)
Balance, December 31, 2005	2,058
Current year stock based compensation	2,258
Allocated to share capital on exercise of options and warrant	(378)
Balance, December 31, 2006	**$ 3,938**

8. Related Party Transactions

In January, 2004, the Company agreed to grant 500,000 common share purchase warrants to a director of the Company in consideration for providing a guarantee in respect of a demand loan bridge facility. Each common share purchase warrant entitles the holder to purchase one common share at a price of $1.00 per share on or before March 3, 2007. The 500,000 common share purchase warrants were exercised on March 1, 2007.

In 2006, the Company paid $28,665 of fees to the law firm of which the Corporate Secretary is a partner. Of these fees, $19,070 was charged to earnings and $9,595 was charged to share capital as share issue costs. In 2005, the Company paid $164,491 of fees to the law firm of which $32,063 was charged to earnings and $132,428 was charged to share capital as share issue costs.

9. Supplemental disclosure of cash flow information

Changes in non-cash working capital were comprised of the following:

	Year ended December 31,	
($000s)	2006	2005
Accounts receivable	$ (12,549)	$ 3,102
Inventory	–	(193)
Prepaid expenses and deposits	(279)	94
Accounts payable and accrued liabilities	693	(10,875)
Net Change	$ (12,135)	$ (7,872)
Net change by activity:		
Operating	$ (5,740)	$ (1,865)
Financing	(73)	(13)
Investing	(6,322)	(5,994)
Net Change	$ (12,135)	$ (7,872)

10. Financial Instruments

CREDIT RISK MANAGEMENT

Accounts receivable include amounts receivable for oil and gas sales, which are generally made to large credit worthy purchasers and amounts receivable from joint venture partners. Accordingly, the Company views credit risk on these amounts as normal for the industry. Of the Company's production, 72% is sold to one marketer. Included in accounts receivable from this marketer at December 31, 2006 is $3.1 million.

FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

Financial instruments include cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities and bank indebtedness. The carrying value of these financial instruments approximate their fair value due to their short term nature or because they bear interest at a floating rate.

11. Commitments

The Company is committed to office lease payments to the end of May, 2009 in the total amount of $0.6 million.

BOARD OF DIRECTORS

Michael Columbos (1) (3)
Chairman, West Energy Ltd.

Ken McCagherty (2)
President and Chief Executive Officer
West Energy Ltd.

M. Bruce Chernoff (1) (3)
President, Caribou Capital

Keith MacDonald (2) (3)
President and Chief Executive Officer
Venturian Natural Resources Limited

Larry Evans (1) (2)
Chairman and Chief Executive Officer
HYgait Resources Ltd.

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.

OFFICERS

Ken McCagherty
President and Chief Executive Officer

Jack Lane
Vice President Operations

Rick Jaggard
Vice President Finance and Chief Financial Officer

Chris Bennett
Vice President Land and Contracts

Graeme Bloy
Vice President Exploration

Keith Greenfield
Corporate Secretary

LEGAL COUNSEL

Burnet Duckworth & Palmer LLP
Calgary

AUDITORS

KPMG LLP
Calgary

BANKERS

National Bank of Canada
Calgary

INDEPENDENT RESERVES ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary

TRANSFER AGENT

CIBC Mellon Trust Company

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Symbol: **WTL**

SUBSIDIARIES

West Asset Corporation

West Energy Corporation

West Energy Partnership

HighWest Acquisition Corp.

665157 BC Ltd

CORPORATE OFFICES

600, 333 - 5th Avenue S.W.
Calgary, Alberta, Canada
T2P 3B6

Phone: (403) 265-5202
Fax: (403) 263-7007
Website: www.westenergy.ca
Inquiries: rjaggard@westenergy.ca

WEST ENERGY LTD.

WEST ENERGY LTD. — ANNUAL REPORT 2006